Review of Duke Energy Progress, LLC's Modified 2020 Integrated Resource Plan Docket No. 2019-225-E Pursuant to Order No. 2021-447

South Carolina Office of Regulatory Staff

October 26, 2021

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Pursuant to Section 58-37-40, South Carolina Code of Laws

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Prepared by the South Carolina Office of Regulatory Staff
and
J. Kennedy and Associates, Inc.

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Executive Summary

The South Carolina Office of Regulatory Staff (“ORS”) provides this Report in review of Duke Energy Progress, LLC (“DEP” or “Company”) Modified 2020 Integrated Resource Plan (“Modified IRP”) that was filed on August 27, 2021 in Docket No. 2019-225-E. ORS, with the assistance of J. Kennedy and Associates, Inc., evaluated DEP’s Modified IRP pursuant to the requirements of S.C. Code Ann. § 58-37-40 (“Section 40”) subsection (C)(3) and assessed whether the Company sufficiently addressed the Public Service Commission of South Carolina’s (“Commission”) Order No. 2021-447 (“Order”). For purposes of this report, DEP and Duke Energy Carolinas, LLC (“DEC”) will collectively be referred to as either the (“Companies”, “Duke” or “Duke Energy".)

As ordered by the Commission, DEP filed the Modified IRP as a stand-alone document within sixty (60) days of the Order and produced Excel workbooks with supportive data, inputs, and results for each resource plan as requested through discovery.

ORS evaluated the Modified IRP pursuant to Section 40(C)(3), which requires ORS “to review the electrical utility's revised plan and submit a report to the Commission assessing the sufficiency of the revised filing” within sixty (60) days of the Company’s filing. ORS determined that the Company sufficiently met the requirements specified in the Order and identified three (3) areas where ongoing evaluation and examination are required. The findings of ORS’s sufficiency evaluation are detailed in the “ORS Review of DEP’s Modified 2020 IRP” section of this Report.

Background of DEP IRP Proceeding

The South Carolina Energy Freedom Act ("Act 62"), signed into law on May 16, 2019, amended the previously established utility IRP statute to include specific requirements that address the utility's peak load and energy forecasts, reliability, alternative resource options, renewable resource options, and retirement of existing resources. Additionally, Act 62 provides substantive and procedural requirements for IRP filings as outlined in Section 40.

Pursuant to Section 40, DEP filed the 2020 IRP with the Commission on September 1, 2020. In the IRP, the Company developed six (6) different resource plans in which it evaluated a range of demand-side, supply-side, storage and other technologies and services that could be relied on to meet its obligations.

On February 5, 2021, ORS filed Direct Testimony and a report ("ORS Report") that reviewed the DEP IRP and assessed the compliance with the statutory requirements in Section 40(B)(1) and (2).[1] ORS filed Revised Direct Testimony and the ORS report on March 4, 2021 to address some minor confidentiality issues. Through its review, ORS determined that the Company complied with the requirements of Section 40, and provided near and long-term recommendations to be addressed by the Company. ORS proposed that the Company be required to modify the 2020 IRP to incorporate the near-term recommendations and address the long-term recommendations in future IRPs and through the Company's ongoing stakeholder processes.

The Company filed Rebuttal Testimony on March 19, 2021, addressing all of ORS's recommendations. In his Rebuttal Testimony, Company witness Glen Snider noted that ORS did "not give a final stamp of approval to the Companies IRPs,"[2] and that ORS identified various areas in which it "recommends the Companies modify certain aspects of their IRPs to provide additional information to aid the Commission in its determination of whether to approve the Companies' IRPs pursuant to the requirements of Act 62."[3]

ORS reviewed DEP's IRP Rebuttal Testimonies, and other than two substantive disputes,[4] concluded in Surrebuttal Testimony that:

[1] ORS filed Revised Direct Testimony and the ORS report on March 4, 2021 to address some minor confidentiality issues.

[2] Snider Rebuttal, p. 22, l. 7.

[3] *Id*. at p. 21, l. 25.

[4] One dispute was discussed in Hayet's Surrebuttal Testimony at pp. 24-26 and concerned the Company's response to ORS recommending the Company to include in the future an additional solar generic resource option reflecting PPA prices that may be available in the market. Mr. Hayet identified $38/megawatt hour ("MWh") as a reasonable proxy price for the Company to use. The second dispute was discussed in ORS witness Kollen's Surrebuttal Testimony at pp 4-6 and concerned ORS's recommendation that the Company to use the same consistent assumptions for the Present Value Revenue Requirement ("PVRR") and customer bill impact analyses.

> [t]he Companies' IRPs as filed with the Commission include the elements required under S.C. Code Ann. §58-37-40(B)(1). Additionally, Duke Energy's witnesses provided additional detail and responses to all of ORS's recommendations for the Companies' 2020 IRPs and responded to all information that was requested to be included or addressed in future IRPs.[5]

South Carolina Coastal Conservation League ("CCL"), Southern Alliance for Clean Energy ("SACE"), Sierra Club, Upstate Forever, Natural Resources Defense Council, the Carolinas Clean Energy Business Association ("CCEBA"), Johnson Development Associates, Inc, Vote Solar and Nucor Steel (collectively the "Intervenors") intervened in the proceeding. The Intervenors made additional recommendations to the Company's IRP regarding Demand Side Management ("DSM") potential, input assumptions, and modeling methodologies. CCEBA recommended that the Commission reject DEP's 2020 IRP and require the Company to file a Modified IRP in this proceeding.[6]

A hearing was held from April 26 to May 6, 2021, wherein Company, ORS, and Intervenor witnesses presented oral testimony for the Commission's consideration. Section 40(C)(1) of Act 62 prescribes that the Commission "shall issue a final order approving, modifying, or denying the plan filed" by the Company no later than three hundred (300) days after the initial filing. Section 40(C)(2) requires the Commission to consider if the plan appropriately balances the seven (7) factors outlined in Section 40(C)(2), and approve the Company's IRP if the Commission determines that the "proposed integrated resource plan represents the most reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed."[7]

On June 28, 2021, the Commission issued Order No. 2021-447 ("Order") that rejected DEP's IRP, and required the Company to make modifications to the 2020 IRP and future IRPs. The Commission ordered the Company to submit a Modified IRP within sixty (60) days and make several changes, among other things, to the resource plans selection, resource cost assumptions, and natural gas prices consistent with the modifications specified in the Order.[8] The Commission also directed the Company to select a "preferred portfolio," as the Commission said that it was "persuaded that a utility's plan must indicate which portfolio it intends to pursue,"[9] though the Commission acknowledged that a utility would be permitted "to change its planned course of action over time in response to changes in circumstances."[10]

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[5] Sandonato Surrebuttal p. 2, l. 8.
[6] Lucas Surrebuttal, pp.13 & 53.
[7] Section 40(C)(1) sets forth the standard of review and Section 40(C)(2) sets forth the factors.
[8] The Order, Section VII - Ordering Paragraphs, pp.85-91.
[9] *Id*. at 11.
[10] *Id*. at 11.

Appendix A of this report contains a summary of the modifications specified in the Order for the Company's Modified 2020 IRP, as well as for the Company's 2021 and 2022 IRPs. Appendix A cross-references each modification to the corresponding "Findings of Fact" (Section IV of the Order), "Review of the Evidence and Evidentiary Conclusions" (Section V of the Order), and "Ordering Paragraphs" (Section VII of the Order). Table A-1 indicates that 32 actions must be performed to meet the requirements of the Order, though only eleven (11) of those must be performed in the Modified 2020 IRP. The remaining actions must be performed in the Company's future IRPs and IRP Updates. Table 2, included in the next section, presents the eleven (11) actions that must be performed in the Modified IRP.

Pursuant to the Order and Section 40(C)(3), the Company filed the Modified IRP with the Commission on August 27, 2021. In the Modified IRP, the Company included nine (9) portfolios that were developed with modeling assumptions similar to the corresponding original six (6) portfolios that were included in the September 2020 IRP, but modified to comply with the requirements of the Order. The original six (6) portfolios that were repeated in the Modified IRP included:

Portfolio A1 - Base Case Without CO_2 - Economic coal retirement dates, no CO_2 policy.

Portfolio B1 - Base Case With CO_2 - Economic coal retirement dates, with CO_2 policy.

Portfolio C1 - Earliest practicable coal retirement dates.

Portfolio D1 - 70% CO_2 Reduction High Wind – Earliest practicable coal retirement dates, relying on more wind resources (on-shore and off-shore).

Portfolio E1 - 70% CO2 Reduction High SMR – Earliest practicable coal retirement dates, relying on small modular reactors.

Portfolio F1 - No New Gas – Economic coal retirement dates, replaces economic additions of natural gas units with battery storage and renewable resources.

The Company's noted that each of the original six (6) portfolios were modified to comply with the Order by including the number "1" after each letter. In each of these modified portfolios the Company included selected Commission-mandated requirements, including the extension of federal ITC for solar development, the increase to the solar interconnection constraint from 500 megawatts ("MW")/year to 750 MW/year, the assumption that all future solar will be of the single axis tracking technology, and the inclusion of the $38/MWh solar Power Purchase Agreement ("PPA") option. IRP.[11]

[11] DEP Modified 2020 IRP, p. 45. Note, in Portfolios D1, E1 and F1, the solar interconnection constraint was increased to 900 MW/year.

The six (6) portfolios, however, did not include all of the Commission mandated requirements. The Company satisfied the Commission requirements for natural gas forecasts and battery cost assumptions separately through three (3) supplemental portfolios, which were identified as Portfolios A2, B2, and C2. Portfolios A2, B2, and C2 were based on Portfolios A1, B1, and C1, but included the additional requirements of using an alternative natural gas price forecast and the National Renewable Energy Laboratory Annual Technology Baseline ("NREL ATB") low battery storage cost forecast as required by the Order (Table A-1 Action Items 21 and 27 respectively).

Portfolios A1, A2, B1, and B2 were subjected to sensitivity analysis in which a single variable was changed in each sensitivity run. The sensitivity variables included inputs such as high/low load forecast, high/low natural gas forecast, high/low solar interconnection limits, high/low solar cost, high/low energy efficiency, and high/low demand response.[12] Scenario Analysis was also performed in which all nine (9) portfolios were evaluated against combinations of different natural gas and CO_2 forecasts. In total each portfolio was evaluated against each of the Company's natural gas price forecasts as created in the original IRP (base, low and high), against each of the alternative natural gas price forecasts (base, low, and high), and against each of three (3) CO_2 forecasts (No CO_2, base CO_2, and high CO_2). In total, based on the nine (9) portfolios and eighteen (18) natural gas/CO_2 cases, the Company performed 162 modeling analyses as part of its Scenario Analysis for the Modified IRP.

Based on the Company's analyses, DEP selected Portfolio C1 as being "the most reasonable and prudent plan" in compliance with the Order.[13] The Company asserts that Portfolio C1 is the best portfolio at achieving the goals of prioritizing retirement of the Company's existing coal fleet in order to accelerate carbon reduction, while ensuring affordability and reliable service for customers.[14]

Although the Company has established the objective of prioritizing retirement of its existing coal fleet, it also recognizes that such an endeavor would be "extraordinary"[15] compared to other utilities, given that Portfolio C1 contemplates retirement of "approximately 10,000 MW of coal generation across the DEP/DEC combined system in an 8-year period."[16] The Company states that Portfolio C1 is diverse in that it adds new natural gas combined cycle and combustion turbine resources, and "more than 15,500 MW of solar in the DEP/DEC combined system, which it states is among the highest level of solar additions of the supplemental portfolios."[17]

[12] DEP Modified 2020 IRP, p.9.
[13] *Id*. at 13.
[14] *Id*. at 13.
[15] *Id*. at 15.
[16] *Id*. at 15.
[17] *Id*. at 15.

While the Company states that Portfolio C1 is the most reasonable and prudent resource plan,[18] it is important to note that Portfolio C1 is not the least cost portfolio amongst the supplemental portfolios PVRR for all the portfolios for both DEP and DEP/DEC combined system. Although there are other lower cost portfolios, the Company notes that "Portfolio C1 represents a balanced approach to planning for more near-term carbon reductions in a prudent and responsible manner that keeps customer affordability and reliability of service as a priority."[19] It is also important to note that any resources that the Company selects may require the issuance of a certificate of public convenience and necessity under the Utility Facility Siting and Environmental Protection Act, S.C. Code Ann. § 58-33-10 et seq. and the recovery of any prudently incurred costs associated with the construction of a new generation facility would be reviewed as part of a base rate proceeding.

Table 1

Pathway	Present Value Revenue Requirement (PVRR) [$B]	
	DEP/DEC Combined	DEP
A1	$78.6	$35.0
A2	$78.8	$35.3
B1	$81.6	$35.1
B2	$82.4	$35.4
C1	$83.2	$36.3
C2	$83.8	$36.3
D1	$100.2	$45.4
E1	$95.2	$42.8
F1	$107.2	$52.6

[18] *Id.* at 13.
[19] *Id.* at 20.

ORS Review of DEP's Modified 2020 IRP

ORS conducted a review of the Company's Modified IRP in accordance with Section 40(C)(3) which states:

> Within sixty days of the electrical utility's revised filing, the Office of Regulatory Staff shall review the electrical utility's revised plan and submit a report to the commission assessing the sufficiency of the revised filing.

Accordingly, the objective of this report is to evaluate the sufficiency of DEP's Modified IRP in meeting the requirements of the Order. To achieve this, ORS reviewed the Modified IRP along with the additional information provided by the Company through discovery, and examined the Company's adjustments to input assumptions, modeling methodologies, and analysis of results.

Table 2 lists the Commission's requirements that must be addressed in the Company's Modified IRP in the current proceeding. Table 2 includes eleven (11) Action Items and indicates whether each Action Item has been sufficiently addressed by the Company. Note that the Action Items in Table 2 are also found in Appendix A, which cross references the Action Items to the respective Findings of Fact included in the Commission's Order. Except for the items related to Findings of Fact #12 and #14, #15-17, and #20 (Action Items 21, 24, and 27 in Table 2), ORS determined the Company sufficiently met the requirements specified in the Order, and no further explanation is included for those items in this report. For the items identified, ORS concluded that DEP has sufficiently met the Commission's requirements for the Modified IRP, but ORS includes additional explanation of the Companies' approach and degree of compliance concerning these items in this Report.

Table 2

Action Items	Summary of Requirements by Commission Order No. 2021-447	DEP Modified IRP Section	ORS Sufficiency Report Section	Sufficient? (Y/N)
1	Select a preferred resource portfolio	Preferred Portfolio (p.13-22) Portfolio C1 Results (p.30-33) Portfolio Results (p.70-73) Selection of a Preferred Portfolio (p.103-115)	Preferred Portfolio Selection (p. 9)	Yes
3	Prepare low and high load forecasts that account for long-term uncertainties	Load Forecast (p.37-40)	Load and Energy Forecast: Sensitivity Analysis (p. 11)	Yes

Action Items	Summary of Requirements by Commission Order No. 2021-447	DEP Modified IRP Section	ORS Sufficiency Report Section	Sufficient? (Y/N)
15	Model all new solar resources as single-axis tracking	SC Supplemental Portfolios (p.5-7) Fixed Tilt vs. Single Axis Tracking Solar Configurations (p.26)	Capacity Value of Solar & Storage (p. 14)	Yes
21	Revise the natural gas price blends in the gas price forecasting methodology	SC Supplemental Portfolios (p.5-7) Fuel Prices (p.41-43) Alternate Gas & Storage Portfolio Results (p.47-48, 51-53, 72-73)	Modeling Assumptions and Inputs: Natural Gas Price Forecasts (p. 12)	Yes, but not in the Preferred Portfolio
22	Revise high & low natural gas price forecasting scenarios	Fuel Prices (Pg. 41-43)	Modeling Assumptions and Inputs: Natural Gas Price Forecasts (p. 12)	Yes
24	Model solar PPAs as selectable resource, and evaluate PPA price sensitivities.	SC Supplemental Portfolios (p.5-7) $38/MWh Solar PPA Option (p.25) Capital Cost Sensitivity Analysis (p.43)	Modeling Assumptions and Inputs: Solar PPA Resource Option (p. 16)	Yes, but only for half of the 750 MW annual limit
25	Update models to account for ITC extension on solar development	SC Supplemental Portfolios (p.5-7) Federal Solar ITC Extension (p.24)	Modeling Assumptions and Inputs: Federal Solar ITC Extension (p. 17)	Yes
26	Adjust the mix of single-axis tracking solar resources in future Public Utility Regulatory Policies Act of 1978 ("PURPA") projects	SC Supplemental Portfolios (p.5-7) Fixed Tilt vs. Single Axis Tracking Solar Configurations (p.26)	Capacity Value of Solar & Storage (p. 14)	Yes
27	Use NREL ATB Low figures for battery storage costs	SC Supplemental Portfolios (p.5-7) NREL ATB Advanced Battery Costs (p.27-28) Alternate Gas & Storage Portfolio Results (p.47-48, 51-53, 72-73)	Modeling Assumptions and Inputs: Battery Storage Costs (p. 18)	Yes, but not in the Preferred Portfolio
29	Assume an interim annual interconnection limit of 750MW for new renewable generation	SC Supplemental Portfolios (p.5-7) Solar Interconnection Limitation (p.23-24) Portfolios & Sensitivity Analysis - Solar, Solar + Storage, and Wind Generation (p.41)	Modeling Assumptions and Inputs: Renewables Interconnection Limit (p. 15)	Yes

Action Items	Summary of Requirements by Commission Order No. 2021-447	DEP Modified IRP Section	ORS Sufficiency Report Section	Sufficient? (Y/N)
30	Include Minimax regret analysis	PVRR Minimax Regret Analysis (p.89-93)	Minimax Regret Analysis (p. 18)	Yes

The following sections provide ORS's assessment of the sufficiency of the Company's Modified IRP.

Preferred Portfolio Selection

In its original 2020 IRP, the Company did not identify a single portfolio out of the six it analyzed to be the Preferred Portfolio, though the Company did refer to the Base Case without Carbon Policy as the "Appropriate Plan."[20] Company witness Snider asserted that the entirety of the IRP, with all six (6) RPs considered as a whole, represent pathways the Company could pursue depending on how the future unfolds. The Commission found that "the identification of a single resource plan as the most reasonable and prudent means of meeting the utility's energy and capacity needs at the time of review is an implied step in the development of an integrated resource plan."[21] The Commission ruled that the six (6) portfolios were too different from each other to be able to collectively be the "most reasonable and prudent" plan. The Commission concluded that DEP must select a single most prudent plan, and ordered, "After updating its modeling assumptions in accordance with the other directives of this Order, Duke is directed to select a preferred resource portfolio in their Modified 2020 IRPs."[22]

In the Modified IRP, DEP selected Portfolio C1 as 'the most reasonable and prudent plan' at this time, in compliance with the Commission's Order.[23] Portfolio C1 is the Earliest Practicable Coal Retirement Portfolio. It differs from Portfolios A1 and B1 (the Base Case without Carbon Policy and the Base Case with Carbon Policy, respectively) in that it accelerates the retirement of all DEP's coal generation by 2030 at the latest, regardless of whether it is the most economic option. Notably, Portfolio C1 is not the least cost portfolio, as its cost, measured by the PVRR, is 3.7% greater than Portfolio A1, and its average bill impact on residential customers is $2 more per month than Portfolio A1 by 2030.[24] Costs are driven by the fact that in retiring the Companies' coal units faster, Portfolio C1 adds more solar and battery storage resources over the study period. Again, while this accomplishes the Company's goal of achieving greater CO_2 reductions over the study period, especially compared to Portfolios A1 and B1, it does lead to higher customer costs.[25]

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20 Snider rebuttal, p. 38, l. 17.
21 Order, p. 10.
22 *Id* at 12.
23 *Id* at 13
24 DEP Modified IRP Table 1-B, p. 10.
25 *Id.*

While DEP selected Portfolio C1 as its Preferred Portfolio in this IRP, it stated that the selection:

> is limited to fulfilling the specific directive to identify the most reasonable and prudent means for meeting the Company's long-term energy and capacity needs and such selection is not intended to dictate its use as the appropriate plan for all other legal and regulatory purposes that integrated resource planning serves. Other legal and regulatory requirements will inform the Company's use of the IRP for future purposes, such as calculating avoided cost pursuant to PURPA and evaluating the cost effectiveness of EE/DSM programs. The Company will address the appropriate IRP analysis to be applied to future dockets as those issues arise.[26]

In response to an ORS discovery request, the Company explained the position as it relates to PURPA Qualifying Facilities ("QF") rates by stating "carbon legislation has not yet been enacted at the state or federal level," and therefore, "it would not be appropriate for customers to pay for 'avoided carbon' costs in QF contracts prior to regulation being enacted that places a real cost on carbon."[27]

Fundamentally, ORS disagrees with the Company's position that it should be permitted to rely on different portfolios depending on the proceeding. Assuming there are no changes in assumptions or circumstances, ORS recommends that the Preferred Portfolio the Company identifies in the IRP should also be used as the base assumption in future proceedings. If there are changes in assumptions or circumstances, then those can be considered as adjustments to the Preferred Portfolio at the time of the future proceeding. ORS's position is based on the fact that once an IRP is approved, utilities typically move forward with the IRP plan, such as taking steps to implement the Action Plan (5-year Action Plan in Duke Energy's case) associated with the Preferred Portfolio.

ORS does agree with the Company that until carbon legislation is enacted at the state or federal level, it would be inappropriate for customers to pay for avoided carbon costs in QF contracts. The Preferred Portfolio should be used in future proceedings, such as avoided cost proceedings. However, that does not mean that avoided carbon costs must be included in the development of QF contracts. The Company proves this by the fact that it developed PVRR results for sensitivity cases both including and excluding the explicit cost of carbon.[28] In future avoided cost proceedings, the Company should use the Preferred Portfolio. However, it should exclude the explicit cost of carbon as it did in the IRP sensitivity analyses.

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[26] DEP Modified IRP, p. 22.
[27] ORS AIR 7-16
[28] DEP Modified IRP, Table 3-H excludes the explicit cost of carbon, and Table 3-I includes the explicit cost of carbon.

Other than the Company's position regarding use of the Preferred Portfolio in future proceedings, the Company sufficiently met the Commission's requirement to select a preferred resource plan in the Modified IRP.

Load and Energy Forecast

Section 40(B)(1)(a) of Act 62 requires utilities to perform a long-term energy and peak demand forecast under "various reasonable scenarios." In the 2020 IRP, DEP addressed the requirement to perform their forecasts under various reasonable scenarios by evaluating the impact on its econometric and end-use statistical models by simulating these models using Moody's Analytics' short-term scenarios, which provided projections of alternative economic drivers, such as gross domestic product and industrial manufacturing indices. These short-term alternative scenarios reflected differences from the Moody's Analytics' baseline forecast during the first thirty (30) months of the forecast and did not change these economic drivers over the entire forecast horizon of 2021 to 2035.

In the Order, the Commission found that DEP's long-term energy and peak load forecasts were reasonable but raised concerns with the Company's evaluation of alternative high and low scenarios.[29] The Commission directed DEP to evaluate its long-term energy and peak load forecasts using long-term high and low scenarios that consider the uncertainty in economic conditions and other factors over the long term.

In the Modified IRP, DEP provided alternative high and low forecast scenarios using adjusted projections of the key forecast economic drivers. ORS reviewed DEP's high and low long-term energy and peak load forecasts and determined that the Company met the requirements of the Order with regard to this issue.

In the Modified IRP analysis, the Company revised the high and low forecast case scenarios for both energy and annual system peak load. Because the base case forecasts were found to be reasonable by the Commission, no changes were made to these forecasts. In the Company's 2020 IRP, DEP modeled high and low economic growth rates, which are the drivers of its forecast modeling, by substituting the Moody's Analytics short term recession and high growth scenarios for the baseline economic projections. This created two alternative forecasts for energy and peak load but did not reflect a long-term high and low growth scenario. In the Modified IRP analysis, the Company made a distinct adjustment to the base case economic projections over the entire 15-year forecast term. The high forecast case scenario was developed by incrementing the growth rate in the economic drivers by 0.3%; the low case forecast was developed by decrementing the base case growth rate of these economic drivers by the same 0.3%.

Table 3 shows the additional high and low case energy and peak load forecasts developed for the Modified IRP compared to the corresponding base case forecasts. As can be seen, the high and low case scenarios reflect a significant change in the 15-year

[29] Commission Order No. 2021-447, p. 86.

compounded growth rates compared to the base case projections. Based on our review, ORS determined that the Company has sufficiently met the requirement of the Commission's Order.

Table 3

Duke Energy Progress						
High/Low Load and Energy Forecast Scenarios vs. Base Case Forecasts						
YEAR	Peak Load (MW)			Energy (GWh)		
	Strong Economic	Base Case	Weak Economic	Strong Economic	Base Case	Weak Economic
2021	14,129	14,118	14,081	63,404	63,389	63,080
2022	14,155	14,143	13,965	63,604	63,568	62,917
2023	14,176	14,130	13,903	63,911	63,776	62,967
2024	14,370	14,290	14,016	64,387	64,157	63,196
2025	14,495	14,381	14,062	64,647	64,475	63,426
2026	14,603	14,456	14,094	65,190	64,895	63,692
2027	14,813	14,629	14,224	65,799	65,379	64,037
2028	14,960	14,740	14,296	66,520	65,969	64,477
2029	15,237	14,976	14,478	67,193	66,509	64,853
2030	15,331	15,035	14,497	67,933	67,111	65,290
2031	15,573	15,233	14,646	68,721	67,754	65,776
2032	15,785	15,404	14,776	69,553	68,435	66,305
2033	15,952	15,531	14,856	70,323	69,059	66,756
2034	16,127	15,666	14,942	71,142	69,726	67,239
2035	16,480	15,966	15,176	72,019	70,446	67,765
Avg. Annual Growth Rate	1.1%	0.9%	0.5%	0.9%	0.8%	0.5%

Modeling Assumptions and Inputs

Natural Gas Price Forecasts

CCEBA and ORS criticized Duke Energy's gas price forecasts in the original 2020 IRP proceeding for relying on market-based forecasts for too many years before transitioning to a fundamentals-based forecast, and for being too low compared to other utility gas forecasts. The Companies' original forecast relied on a market-based price strip for ten (10) years before beginning to gradually transition to a fundamentals-based forecast over the next five (5) years. This led to concerns that the Company understated its fuel price forecast throughout its 15-year planning horizon. CCEBA witness Lucas suggested transitioning to a fundamentals-based forecast over a shorter time horizon, and the Commission agreed, writing, "Duke is directed to remodel its portfolios using natural gas pricing forecasts that rely on market prices for eighteen (18) months before transitioning over eighteen (18) months to the average of at least two fundamentals-based forecasts, as recommended by Mr. Lucas."[30]

ORS reviewed the Company's revised gas forecasts and confirmed the revised forecasts rely on a NYMEX market-based price strip for eighteen months before transitioning over an eighteen-month period to the average of the IHS Markit and the Energy Information Administration fundamentals forecasts.[31] The resulting modified gas prices are similar to the original forecasts in the 2020-2022 and 2035-2050 periods but are higher during the 2023-2034 period. The Company provided a graph comparing the original and alternate gas forecasts in Figure 3-C.[32]

It should be noted that when the Company developed portfolios in the Modified IRP, they only used the revised natural gas forecasts in the analysis of portfolios A2, B2, and C2. The other six portfolios, including the Company's Preferred Portfolio C1, used the original gas forecast from the 2020 IRP.[33] The "Other Considerations – Multiple Runs" section below discusses this issue in further detail.

Witness Lucas also recommended that the Companies use the 25th and 75th percentile results as the basis of developing its high and low gas price forecasts, rather than the 10th and 90th percentiles used in the 2020 IRP, and the Commission correspondingly directed the Companies to "adjust its high and low-price scenarios to reflect the 25th and 75th percentile results to reduce price volatility" in Section V (Review of the Evidence and Evidentiary Conclusions) of the Order.[34] This directive was not adopted in the Ordering Paragraphs of the Order. However, the Company did reflect this change and based their revised high and low gas forecasts off the 25th and 75th percentile cases in portfolios A2, B2, and C2.[35]

The Company ran sensitivity analyses based on high and low gas price scenarios, which were selected based on the alternate high forecast and the original low forecast, respectively. The Company chose these scenarios because they "represent the highest and lowest forecasts among the six (6) natural gas price forecasts" that were developed.[36] For the sensitivity analyses, the Company reoptimized the expansion plan of portfolios B1 and B2 under the high and low gas forecasts to determine the potential impact of these gas prices cases on those portfolios.

ORS notes that DEP's Preferred Portfolio C1 utilized the original natural gas forecasts from the 2020 IRP, not the Commission-required forecasts. However, as part of the Company's Scenario Analysis assessment, they did evaluate all of the portfolios, including Portfolio C1, against the alternate low, base, and high natural gas forecasts.

[30] Commission Order No. 2021-447, p. 64
[31] ORS AIR 7-27b
[32] DEP Modified IRP, p. 42
[33] DEP Modified IRP, Table A-1, p. 8
[34] Commission Order No. 2021-447, p. 64
[35] ORS AIR 7-27d and DEP Modified IRP, p. 42
[36] DEP Modified IRP, p. 43

Additionally, the Order requires the Companies to review their natural gas price forecasting methodology and investigate alternative approaches through stakeholder engagement in future IRPs.[37]

Based on our review of the Company's gas price forecasting analyses, ORS concludes that DEP revised its gas price forecast assumptions and sufficiently complied with the Commission's requirements.

Capacity Value of Solar & Storage

DEP's initial 2020 IRP modeled both fixed tilt and single axis tracking solar, assuming 40% of future solar additions would be fixed tilt and 60% would be single axis tracking. Multiple intervenors pointed out that this did not align with the results of Duke Energy's Competitive Procurement of Renewable Energy ("CPRE") Tranche 2, in which single axis tracking proposals dominated fixed tilt. The assumption that 40% of future resources would be fixed tilt was considered by intervenors to be an unfair limit on the capacity value of solar in the Companies' modeling. The Commission agreed with this reasoning, ordering that "Duke should make a number of changes to its development of effective load carrying capability ("ELCC") values and revisions to its capacity expansion modeling that incorporates those ELCC values, including … Modeling all future solar as single-axis tracking consistent with industry trends."[38]

Because the ELCC of solar depends on many factors, such as the amount of solar already on the system, the load shape, the solar shape at the solar resource location, and the tracking characteristics of the resource, updating the solar ELCC values to reflect the change to single axis tracking would not be a simple matter. As is the typical practice of utilities, and in compliance with the Commission's requirements,[39] the Company will need to continue to study and refine their estimates of the capacity value of solar based on the above considerations in future IRPs. The Company has committed to updating the solar ELCC studies in future IRPs, which will provide more detailed analysis of solar resources' capacity values at different penetration levels.[40]

Presently, the change to 100% single axis tracking in the Modified IRP means that the Company has assigned greater capacity value to future solar resources in the modeling analyses. Based on the Company's responses to previous data requests in this proceeding, the change to all tracking solar results in, on average, about 75% greater capacity values in the winter and 25% greater capacity values in the summer than the previously modeled mix of fixed and tracking solar.[41]

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[37] Order No. 2021-447, Ordering Paragraph 21(f) pp.90. Action Item 21 in Appendix Table A-1

[38] Commission Order 2021-447, p. 87.

[39] Order No. 2021-447, Ordering Paragraph 21(j) pp.90. Action Item 14 in Appendix Table A-1

[40] The Company indicated in response to ORS discovery AIR 7-39 that Duke "is currently working with Astrape to develop the scope and work plan to conduct new resource adequacy and ELCC studies and to address the corresponding Commission directives." AIR 7-39

[41] These percentages are based on a comparing the capacity contributions of single axis tracking to a mix of tracking and fixed solar technologies in CPRE Tranches 1-4. See ORS AIR 2-4 and 2-5. Duke assumes

Table 2-A in the Modified IRP Report[42] entitled, "Renewable Energy and Battery Storage Input and Assumption Changes" indicates that the Company has modeled all future solar resources as single axis tracking. Also, Table 3-AA in the Modified IRP Report[43] entitled, "Assumptions of Load, Capacity and Reserves Tables" confirms that the Company has assumed winter capacity values between 2% and 1.1%, declining as solar penetration rises. This is higher than the 1% winter capacity value the Company assumed in the initial IRP and matches the capacity values for single axis tracking solar resources found in the 2018 Solar ELCC Study by Astrapé. Taken together, these assumptions reflect the fact that the Company modified its modeling assumptions to rely on 100% single axis tracking solar resources.[44]

The Company's modeling of solar as single axis tracking sufficiently meet the requirements of the Order. The Company's modeling also sufficiently meets the Order's requirement that the Company should adjust the mix of single axis tracking solar resources in PURPA projects (Action Item 27 in Table 2).

Renewables Interconnection Limit

In the original filing, the Companies imposed a 500 MW per year limit on new solar additions, citing the level of solar interconnections that occurred in recent years. The Commission found that the new solar limit was too low, by stating:

> While the Commission accepts Mr. Kalemba's claim that physical and technical restraints on interconnection justify some limitation on the scope and scale of additions of new resources in Duke's modeling, a 500 MW annual limitation on the interconnection of renewables throughout the planning period is not reasonable, in light of Duke's demonstrated ability to interconnect greater amounts of generation in past years, the implementation of queue reform, and technical advancements in recent and coming years. The Commission agrees with witness Lucas that a reasonable and prudent IRP would reflect increases in the amount of interconnection over and above the 500 MW cap established by Duke in its base cases.[45]

The Commission ordered the Companies to allow for the possibility of interconnecting up to 750 MW of solar and storage resources per year.[46] Based on the greater amount of existing solar in DEP and higher load in DEC, the Companies assigned an annual limit of

winter capacity values that average 2.24% for single axis tracking, and 1.26% for a mix of tracking and fixed solar. Summer capacity values average 27% and 21%, respectively.

[42] See pp. 24-25

[43] See p. 110.

[44] Duke Energy Carolinas and Duke Energy Progress Solar Capacity Value Study, 8/27/2018, see Table S5 on p. 11.

[45] Commission Order No. 2021-447, p. 81.

[46] *Id.* at 88.

300 MW to DEP and a 450 MW to DEC, making the combined system limit 750 MW.[47] This 750 MW limit applied to Duke's Portfolios A1, A2, B1, B2, C1, and C2. Portfolios D, E, and F allowed for the possibility of interconnecting even more solar resources–up to 900 MW per year.

The Company's Preferred Portfolio C1 takes full advantage of this interconnection limit increase. The Company noted in a discovery response, "In all years of the Preferred Portfolio, except 2030, the model selected the maximum amount of solar units available up to the 750 MW limit regardless of price assumptions."[48] It follows that this annual 750 MW limit could be a bottleneck in the addition of economic solar. Put another way, it is possible that if this limit were increased the model would add cost effective solar generation faster, and potentially more of it.

Based on our review, ORS determined that the Company has sufficiently met the Commission's requirement to increase the annual solar interconnection limit to 750 MW in this Modified IRP.

Solar PPA Resource Option

In the initial IRP proceeding, multiple witnesses pointed out that the Company modeled all its solar as company-owned solar at higher prices than are available as PPAs. The Commission found "persuasive the testimony of ORS witness Hayet and CCEBA witness Lucas that it was unreasonable for the Companies not to model additional solar resources at prices representative of those actually obtained by the Companies through its competitive solicitations."[49] The Commission noted that the result of the Companies' CPRE Tranche 2 "provides adequate assurance that there is a robust market for independently produced solar resources in the Carolinas, and that such solar resources could be procured at a cost below the Companies' assumed Levelized Cost of Electricity ("LCOE") costs."[50]

Accordingly, the Commission ordered that "In the Modified IRP and IRP Update, Duke shall include third-party solar PPAs priced at $38/MWh as a selectable resource. Any change to this pricing in subsequent IRPs or IRP Updates shall be supported by a reasonable investigation into market conditions in Duke's service territories." Additionally, DEP was ordered that these solar PPAs "shall assume a contract length of at least 20 years, and operational characteristics identical to CPRE projects," and "shall include sensitivities in the modified IRP for PPA pricing at $36/MWh and $40/MWh."[51]

The Company included $38/MWh solar PPAs as a model selectable option in the Modified IRP. However, of the 750 MW annual interconnection limit, the Companies only permitted half of that capacity limit to be available to be selected as PPA resources. The remaining

[47] DEP Modified IRP, p. 25.
[48] ORS AIR 7-18.
[49] Commission Order No. 2021-447, p. 68.
[50] *Id.* at 69.
[51] *Id.* at 88.

half of the capacity limit was available for the model to select as utility-owned solar projects, which was modeled at a significantly higher price ($[redacted]/MWh).[52] The stated reason for this limitation was "to provide a balanced portfolio of solar generation," and because of depth-of-market concerns, including uncertainties in land acquisition, the supply chain, and labor costs.[53]

In addition, the Company modeled its solar PPAs as 20-year PPAs,[54] with curtailable characteristics to meet CPRE requirements,[55] and ran $36 and $40/MWh solar PPA sensitivities on portfolios A1, A2, B1, and B2.[56] The Company considered these four cases to be the "economically optimized portfolios."[57] The Company did not perform these PPA price sensitivity evaluations on the Preferred Portfolio, C1.

After review of the Commission requirements, DEP's Modified IRP, and the Company's reason for limiting solar PPAs, ORS concludes that DEP complied with the Order, but ORS points out that the Company imposed limitations on the selection of PPAs to only half of the 750 MW annual interconnection limit and only performed the PPA sensitivity analysis on four of the nine Portfolios it analyzed.

Federal Solar ITC Extension

DEP released its initial IRP on September 1, 2020, and at that time the Federal solar ITC was set to phase out by 2023. In December of 2020 the Federal ITC was extended, allowing a higher tax credit in 2022 and 2023, and allowing the tax credit to continue indefinitely thereafter at 10%. The Commission ordered that Duke incorporate these changes into its Modified IRP.

ORS has reviewed the Company's modeling input assumptions and confirmed that the extended tax credits have been appropriately modeled.[58] ORS notes that the Company's modeling inputs assume the "safe harbor" provisions are taken advantage of, allowing Duke Energy to lock in the benefits of the ITC for up to four years while the project is under construction. This is a reasonable assumption that is in the best interest of customers.

Based on ORS's review, the Company has sufficiently satisfied the requirement to update its solar ITC assumptions according to the change in law since it filed its original IRP.

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[52] DEP Modified IRP, p. 26. Also see ORS's report, "Review of Duke Energy Carolina's, LLC 2020 IRP," which was attached as Exhibit AMS-1 to Mr. Sandonato's February 5, 2021 Direct Testimony, at p. 75.
[53] ORS AIR 7-17 and Modified IRP p. 26.
[54] DEP Modified IRP, p. 25.
[55] ORS AIR 7-23.
[56] DEP Modified IRP, p. 56 and following.
[57] *Id.* at 44.
[58] Duke Modified IRP Model Inputs excel sheet, New Unit Cost tab.

Battery Storage Costs

CCEBA Witness Lucas argued in the original IRP proceeding that Duke Energy's battery costs were too high and did not accurately reflect the true costs of the technology. He recommended that the Companies use the NREL ATB Low forecast instead. The Commission ordered Duke Energy to use the NREL ATB Low price battery forecast in its Modified IRP.[59]

On reviewing Duke's Modified IRP, ORS found that the Company did use the NREL ATB Low price forecast; however, the Company did not use it in every portfolio. For capacity expansion optimization, Portfolios A2, B2, and C2, the Companies used the specified NREL battery price forecast. However, for Portfolios A1, B1, C1, D1, E1, and F1, the Company used Duke Energy's battery price forecast from the original 2020 IRP filing.[60] This means that Duke's Preferred Portfolio C1 does not include the Commission required battery price forecast. The "Other Considerations – Multiple Runs" section discusses this issue in further detail.

ORS concludes that Duke technically met the requirements of the Commission's order to model battery price forecasts using the NREL ATB Low forecast, but notes that Duke's Preferred Portfolio assumed the original battery price forecast from the 2020 IRP, not the Commission required NREL ATB Low price forecast.

Minimax Regret Analysis

Multiple intervenors and ORS criticized DEP in the initial 2020 IRP for simply producing qualitative, rather than quantitative risk analyses. CCEBA Witness Lucas suggested that DEP conduct Minimax Regret Analyses as a simple, easy to implement and understand risk analysis. The Commission ordered that "[i]n future IRPs, including Modified IRPs and IRP Updates, Duke shall perform and include a minimax regret analysis of the type described and performed in this proceeding by ORS Witness Kollen."[61]

DEP satisfied the Commission's requirement by including a minimax regret analysis like the one performed by ORS witness Kollen in the original 2020 IRP proceeding.[62] The Modified IRP notes some of Duke Energy's reservations with the analysis, including the fact that it considers each scenario as equally likely, and the assumption that each portfolio is fixed and unable to adapt to policy or market changes as they develop. ORS agrees that further consideration of risk analyses should be included in the stakeholder process prior to the next IRP.

[59] Commission Order No. 2021-447, p. 88.
[60] ORS AIR 7-28 and DEP Modified IRP Table 2-A, pp. 23-24.
[61] Commission Order No. 2021-509, "Order Holding 2021 IRP Update in Abeyance and Granting Reconsideration and Clarification of Order No. 2021-447", August 20, 2021, Ordering Paragraph 3, page 12. In its clarification order, the Commission clarified that in the original order, it had inadvertently referred to CCEBA witness Lucas, but intended to refer to ORS Witness Kollen.
[62] DEP Modified IRP, pp. 89-93.

With regard to the Modified IRP, DEP sufficiently met the Minimax Regret Analysis requirements that were established by the Commission.

Other Considerations – Multiple Runs

Much of the complexity in this Modified IRP stems from the fact that Duke Energy chose to make multiple runs with differing assumptions for Portfolios A, B and C. A much simpler solution would have been to incorporate all of the Commission-required adjustments into the original 2020 IRP portfolios and re-run each portfolio only once under those consistent assumptions.

Instead, DEP's Portfolios A1, B1 and C1 assumed different battery and natural gas price forecasts than portfolios A2, B2 and C2. The second set of portfolios used the Commission-ordered updated battery and natural gas forecasts, while the first set of portfolios used the gas and battery forecasts from the original IRP. DEP provides its reasoning for this choice as follows:[63]

> Finally, the assumptions in Portfolio C1 are more reasonable and appropriate for resource planning than the more aggressive cost assumptions incorporated in Portfolio A2 or B2 or C2. Specifically, as described in greater detail in section 2, the Company views the use of a low battery cost forecast, which is by definition less probable than a moderate forecast, as better suited for sensitivity or scenario analysis rather than a base case assumption. Similarly, a natural gas forecast that incorporates an early transition to a fundamental fuel forecast would be inconsistent with actual market information in the way fuel procurement is planned, managed, and accounted for, and thus would not be a prudent base case assumption, but rather better suited as a price sensitivity.

The use of different gas and battery price assumptions meant that DEP performed an extra step in order to compare total PVRR costs on an apples-to-apples basis. DEP was concerned that otherwise, portfolios with the lower gas or battery price assumptions would appear artificially lower in cost (PVRR) and not necessarily directly comparable to other portfolios. These lower PVRR values would not be due to any actual underlying benefit or efficiency in the portfolio, but only because the portfolio assumed natural gas or batteries were going to be cheaper than other portfolios.

To avoid unfairly advantaging the portfolios with lower battery prices, DEP modeled expansion plan optimization and production costs using different methodologies. As discussed above, the portfolios labelled 1 (A1, B1 and C1) were optimized using the natural gas and battery price forecasts from the original 2020 IRP, while the portfolios labelled 2 (A2, B2 and C2) were optimized under the Commission-ordered updated battery and natural gas forecasts. Because of its concern that reporting production costs under different sets of price assumptions would not allow for apples-to-apples comparisons of cost between portfolios, after developing optimal expansion plans in

[63] DEP Modified IRP, pp. 19.

Portfolios A2, B2, and C2, DEP developed final PVRR results using the same consistent assumptions as were used in Portfolios A1, B1 and C1. That is, in portfolios A2, B2 and C2, DEP priced out final battery capital costs and natural gas costs using the original 2020 IRP battery and gas price forecasts.[64] ORS notes that this means portfolios A2, B2 and C2 do not achieve optimal cost results given that they were optimized under different cost assumptions than used in the final PVRR cost determination.

Conclusion

Based on a review of the Order and DEP's Modified IRP, ORS concludes that DEP has sufficiently met all of the requirements set by the Commission Order for the Modified IRP. However, ORS notes that while the Company satisfied the Commission's requirement to select a Preferred Portfolio, the Company indicated it does not necessarily intend to use the Preferred Portfolio in upcoming regulatory proceedings, such as for developing avoided costs. From ORS's perspective, the IRP process, and the selection of a Preferred Portfolio in particular, is important for future regulatory proceedings to ensure that a consistent base case has been properly determined and reviewed and is ready to be used in those proceedings. Should the Company choose to introduce a new base case for avoided cost purposes that differs from the Preferred Portfolio, ORS reserves its rights to review and make the appropriate recommendations.

While DEP has met the Commission's requirements, there are three items that DEP should continue to evaluate and examine further over time.

1. $38/MWh solar PPAs as a selectable option for only half of the 750 MW renewable interconnection limit per year.
2. The use of the Company's original natural gas forecast, not the Commission-required updated gas forecast, in the Preferred Portfolio expansion plan optimization.
3. The use of the Company's original battery cost forecast, not the Commission-required NREL ATB Low battery forecast, in its Preferred Portfolio expansion plan optimization.

ORS determined that DEP's Modified IRP is sufficient to meet the requirements set by the Commission in Order No. 2021-447.

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[64] Id. at 20.

Appendix A

Table A-1

Action Items	Summary of Requirements by Commission Order No. 2021-447	Section IV - Finding of Facts	Section V - Evidentiary Review	Section VII - Ordering Paragraphs	Adoption Timeline
1	Select a preferred resource portfolio				Modified IRP
2	Implement all commitments made in response to ORS recommendations in Duke's rebuttal testimony			22	Future IRPs & IRP Updates
3	Prepare low and high load forecasts that account for long-term uncertainties	1	B.1. (Pg. 22-25)	1	Modified IRP
4	Uncertainties included in load forecasts and resource adequacy study must be consistent		B.1. (Pg. 22-25)	1	Future IRPs
5	Include a technical appendix detailing the load forecast methodology			21.a.	Future IRPs
6	Use the Utility Cost Test (UCT) to measure economic potential of Energy Efficiency ("EE")/DSM	2	B.2 (Pg. 25-34)	2	Future IRPs & IRP Updates
7	Improve assumptions regarding impact of existing and emerging technologies on EE/DSM savings	3	B.2 (Pg. 25-34)	3, 21.d.	Future IRPs & IRP Updates
8	Reduce the dependance of residential saving projections on behavioral programs	4	B.2 (Pg. 25-34)	3	Future IRPs & IRP Updates
9	Identify the EE/DSM recommendations that were and were not adopted in developing MPS and IRP		B.2 (Pg. 25-34)	3	Future IRPs & IRP Updates
10	Evaluate high and low EE/DSM cases across a range of fuel and CO_2 assumptions		B.2 (Pg. 28,31,33,34)	4, 21.e.	Future IRPs
11	Improve the methodology for deriving low EE/DSM forecasts			21.e.	Future IRPs
12	Study the impact of extreme winter weather on peak loads and improve the modeling methodology	5	C (Pg. 34-39)	5, 21.b., 21.c.	Future IRPs

Action Items	Summary of Requirements by Commission Order No. 2021-447	Section IV - Finding of Facts	Section V - Evidentiary Review	Section VII - Ordering Paragraphs	Adoption Timeline
13	Perform single-step optimization in capacity expansion modeling	6	D (Pg. 40-45)	6.a.	Next IRP Update
14	Develop an ELCC Surface to obtain combined capacity values for solar and storage; Further investigate ELCC for solar & storage	6, 10	D (Pg. 40-45)	6.b., 21.j.	Next IRP Update, Future IRPs
15	Model all new solar resources as single-axis tracking	8, 19	D (Pg. 46-47)	6.c.ii., 15	Modified IRP
16	Recalculate solar and storage ELCC relative to 2035 load profile	9	D (Pg. 47-48)	6.c.i.	- [65]
17	Update DR values to include those identified in Winter Peak Demand Reduction Potential Assessment			6.c.iii.	- [65]
18	Perform a comprehensive coal retirement analysis	11	E (Pg. 48-53)	7, 21.g.	2022 IRP
19	Address and quantify the supply risk on natural gas availability and pricing	13	F.1 (Pg. 53-54)	8	Next Full IRP
20	Address the risk of non-availability of firm natural gas capacity for generation units during winter peaks	13	F.1 (Pg. 53-54)	9	Next Full IRP
21	Revise the natural gas price blends in the gas price forecasting methodology	12, 14	F.2 (Pg. 54-64)	10, 21.f.	Modified IRP, IRP Update, Future IRPs
22	Revise high & low natural gas price forecasting scenarios	12, 14	F.2 (Pg. 57-58)		Modified IRP
23	Use reasonable capital cost assumption for combustion turbine resource option			21.h.	Future IRPs
24	Model solar PPAs as selectable resource, and evaluate PPA price sensitivities.	15, 16, 17	F.3 (Pg. 64-70)	11, 12, 13, 20, 21.i.	Modified IRP, IRP Update, Future IRPs

[65] Order No. 2021-447 did not prescribe a timeline for these action items. The Company indicated in response to discovery that Duke "is currently working with Astrape to develop the scope and work plan to conduct new resource adequacy and ELCC studies and to address the corresponding Commission directives." AIR 7-39

Action Items	Summary of Requirements by Commission Order No. 2021-447	Section IV - Finding of Facts	Section V - Evidentiary Review	Section VII - Ordering Paragraphs	Adoption Timeline
25	Update models to account for ITC extension on solar development	18	F.4 (Pg. 70-72)	14	Modified IRP
26	Adjust the mix of single-axis tracking solar resources in future PURPA projects	19	F.4 (Pg. 72-74)	15	Modified IRP
27	Use NREL ATB Low figures for battery storage costs; Improve battery cost assumptions	20	F.5 (Pg. 74-77)	16, 21.h.	Modified IRP, Future IRPs
28	Evaluate the appropriate interconnection limit for new renewables generation	21, 22, 23	F.6 (Pg. 78-82)	18	Next Full IRP
29	Assume an interim annual interconnection limit of 750MW for new renewable generation	21, 22, 23	F.6 (Pg. 78-82)	17	Modified IRP
30	Include Minimax regret analysis & other risk analyses	24	G (Pg. 82-84)	19, 21.k.	Modified IRP, IRP Update, Future IRPs
31	Revise calculation of average customer retail rate impact to match Present Value Revenue Requirement (PVRR) calculations			21.l.	Future IRPs
32	Provide updates regarding, and benefits of, Southeast Energy Exchange Market ("SEEM")			21.m.	Future IRPs